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BEFORE THE ARIZONA CORPORATION C

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AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF
ARIZONA PUBLIC SERVICE COMPANY FOR A
HEARING TO DETERMINE THE FAIR VALUE
OF THE UTILITY PROPERTY OF THE
COMPANY FOR RATEMAKING PURPOSES, TO
FIX A JUST AND REASONABLE RATE OF
RETURN THEREON, TO APPROVE RATE
SCHEDULES DESIGNED TO DEVELOP SUCH
RETURN, AND TO AMEND DECISION NO.
67744.

DOCKET NO. E-01345A-05-0816

IN THE MATTER OF THE INQUIRY INTO THE
FREQUENCY OF UNPLANNED OUTAGES
DURING 2005 AT PALO VERDE NUCLEAR
GENERATING STATION, THE CAUSES OF THE
OUTAGES, THE PROCUREMENT OF
REPLACEMENT POWER AND THE IMPACT OF
THE OUTAGES ON ARIZONA PUBLIC
SERVICE COMPANY'S CUSTOMERS.

DOCKET NO. E-01345A-05-0826

IN THE MATTER OF THE AUDIT OF THE FUEL
AND PURCHASED POWER PRACTICES AND
COSTS OF THE ARIZONA PUBLIC SERVICE
COMPANY.

DOCKET NO. E-01345A-05-0827

ARIZONA CORPORATION COMMISSION
STAFF'S REPLY BRIEF

February 16, 2007

Arizona Corporation Commission
DOCKETED

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TABLE OF CONTENTS

I.	THE COMMISSION SHOULD REJECT APS' PROPOSED "ATTRITION ADJUSTMENTS," AND SHOULD INSTEAD RELY ON TRADITIONAL COST OS SERVICE PRINCIPLES TO ESTABLISH APS' RATES	1
A.	<u>The Commission Is Not Required As A Matter of Law To Use Future Projections To Establish Rates</u>	1
B.	<u>The Projections Provided By APS In This Case Are Not Helpful And Should Be Disregarded</u>	4
C.	<u>Staff's Audit Shows That APS' Current Rates Appropriately Recover The Company's Non-Fuel Costs</u>	7
1.	<i>Transmission Costs</i>	7
2.	<i>Capacity Costs</i>	7
3.	<i>Distribution And Other Costs</i>	8
4.	<i>Rate Relief That Addresses The Company's Rising Fuel Costs Is Sufficient Relief At This Time</i>	8
5.	<i>APS' November 28, 2006 Response to Chairman Hatch-Miller's Letter Is Not A Basis For Concluding That Earnings Attrition Is Occurring Due To Customer Growth</i>	10
II.	COST OF CAPITAL	11
III.	PENSION EXPENSE	16
IV.	CASH WORKING CAPITAL.....	17
A.	<u>Depreciation And Deferred Taxes</u>	17
B.	<u>Interest Expense</u>	19
C.	<u>Amortized Prepaid Insurance And Nuclear Fuel Expenses</u>	19
D.	<u>Arizona Precedent</u>	19
V.	INVESTMENT TAX CREDITS	20
VI.	BARK BEETLE REMEDIATION	21

1	VII.	SUNDANCE UNITS	22
2	VIII.	LOBBYING EXPENSES	23
3	IX.	INCENTIVE COMPENSATION	25
4	X.	PROPERTY TAX EXPENSE	26
5	XI.	PALO VERDE ISSUES.....	27
6			
7	A.	<u>APS Documents And NRC Evaluations Are</u> <u>Virtually The Only Source For Determining the Level</u> <u>of The Company's Knowledge About The Details Of Its Performance</u>	27
8			
9	B.	<u>The Emergency Diesel Generator Governor Failure (March 18-21)</u>	29
10	C.	<u>Unit 1 Reactor Trip And Outage Extension Due to Operator</u> <u>Error (August 26-28, 2005)</u>	30
11	D.	<u>Unit 2 And 3 Refueling Water Tanks Inoperability (October 11-20, 2005)</u>	30
12	E.	<u>Measuring The Impact</u>	33
13		1. <i>Offsetting coal Operations Against The Impact of Palo Verde</i> <i>Outages Is Not Reasonable</i>	33
14		2. <i>Lost Off-System Sales</i>	34
15		3. <i>The Nuclear Performance Standard Is An Appropriate</i> <i>Responsive Measure</i>	35
16			
17	XII.	ENVIRONMENTAL IMPROVEMENT CHARGE	36
18	XIII.	DEMAND SIDE MANAGEMENT	37
19	XIV.	POWER SUPPLY ADJUSTER.....	38
20	XV.	RATE DESIGN	38
21	XVI.	DEMAND RESPONSE	39
22	XVII.	MISCELLANEOUS ISSUES	39
23	XVIII.	CONCLUSION	40
24			
25			

1 Arizona Corporation Commission Staff ("Staff") hereby files its responsive brief in this
2 matter. This brief primarily attempts to respond to the arguments against Staff's recommendations
3 set forth by the other parties in their respective closing briefs. To the extent that this brief does not
4 address any particular issue, Staff relies upon its discussion of those issues set forth in its opening
5 brief, filed on January 22, 2007.

6 **I. THE COMMISSION SHOULD REJECT APS' PROPOSED "ATTRITION**
7 **ADJUSTMENTS" AND SHOULD INSTEAD RELY ON TRADITIONAL COST OF**
8 **SERVICE PRINCIPLES TO ESTABLISH APS' RATES.**

9 In this case, APS has argued that the Commission must grant APS its entire rate request if the
10 Company is to avoid financial ruin. This request was made clear in the testimony of APS witness
11 Steven Wheeler. (Wheeler Rebuttal Test., hereinafter referred to as "Wheeler Rebuttal", Ex. APS-2
12 at 2, 3, 9, 18, 25; *see also* Tr. at 4240-43; 4264-65). APS bases this argument on the following
13 assertions, all of which are disputed, unreliable, or meritless: 1) APS claims that the Commission is
14 *required as a matter of law* to consider the projected impact of a rate decision on APS' financial
15 criteria, 2) APS claims that these forecasts show that, from a quantitative view, APS will not meet
16 the required credit metrics to maintain an investment grade credit rating under either the Staff or
17 RUCO proposals, 3) APS claims that the cost of customer growth is greater than the revenues
18 generated by that growth, thereby causing the Company's rates to be inadequate. This brief will
19 subsequently discuss each of these contentions in turn.

20 **A. The Commission is not required as a matter of law to use future projections to**
21 **establish rates.**

22 APS claims that the Commission is *required as a matter of law* to consider the projected
23 impact of a rate decision on APS' financial criteria. In support of this assertion, APS cites *Federal*
24 *Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), and *Bluefield Water Works &*
25 *Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923). These decisions in
large part address whether the federal constitution requires states to follow any specific method when

1 setting rates. These decisions specifically reject that conclusion and instead hold that, for purposes of
2 determining whether a rate decision is confiscatory for purposes of federal due process, it is the “end
3 result” that is significant, not the specific method.

4 These cases identify three factors to consider in determining whether a rate decision produces
5 rates that satisfy federal constitutional standards:

6 The return should be reasonably sufficient to assure confidence in the financial
7 soundness of the utility, and should be adequate, under efficient and economical
8 management, to maintain and support its credit and enable it to raise the money
9 necessary for the proper discharge of its public duties.

10 *Bluefield*, 262 U.S. at 693. Contrary to APS’ assertions, these cases do not identify any one method
11 for satisfying these factors and are careful to point out that whether a particular rate decision
12 constitutes just compensation “depends upon many circumstances and must be determined by the
13 exercise of a fair and enlightened judgment, *having regard to all relevant facts . . .*” *Id.* at 692
(emphasis added).

14 APS argues that the Commission cannot ascertain whether proposed rates will be adequate “to
15 maintain and support its credit” or “to raise the money necessary for the proper discharge of its public
16 duties” without considering the impact of those proposed rates in some future period. (APS’ Br. at 9-
17 10). APS then produces forecasts of the future period of its choosing, claims that these forecasts
18 show that it will suffer a credit-rating downgrade unless its entire rate request is granted, and suggests
19 that the Commission should disregard all other evidence *except* the forecasts. (Wheeler Rebuttal at 2,
20 18; Dittmer Surrebuttal Test., hereinafter referred to as “Dittmer Surrebuttal”, Ex. S-37 at 4-5). In
21 APS’ view, its financial forecasts of future periods become the automatic and binding formula for
22 determining its revenue requirement. This result is the complete opposite of the holdings of *Hope*
23 and *Bluefield*, which urge a consideration of all relevant factors and expressly disavow a mechanistic
24 reliance on any single formula.

1 In other words, APS believes that the Commission *is required as a matter of law* to establish
2 rates exclusively by reference to APS' financial ratios, which are based upon *forecasts*. APS'
3 argument implies that federal constitutional standards *require* the use of a future test year. (See Tr. at
4 4199-4200). APS not only fails to cite any federal cases to specifically support this theory but also
5 fails to reconcile it with Arizona law. In fact, Arizona cases suggest that rates should be set by
6 reference to an *historic* test year and that a utility's rate base must be established by reference to the
7 fair value of its property that is "used and useful" in providing public service. See Ariz. Const. art.
8 XV, § 14.

9 Certainly, Commission decisions must comport with federal constitutional standards.
10 However, the method advocated by APS is not required by the federal constitution, and is also at
11 odds with the Arizona Constitution. As the Arizona Supreme Court has stated,

12 It is clear, therefore, that under our constitution as interpreted by this court, *the*
13 *Commission is required to find the fair value of the company's property and use*
14 *such finding as a rate base for the purpose of calculating what are just and*
15 *reasonable rates.* The *Hope* case cannot be used by the Commission. To do so
16 would violate our constitution. The statute under consideration in that case
prescribed no formula for establishing a rate base. While our constitution does
not establish a formula for arriving at fair value, *it does require such value to be*
found and used as the base in fixing rates. The reasonableness and justness of the
rates must be related to this finding of fair value.

17 *Simms v. Round Valley Light and Power Co.*, 80 Ariz. 145, 151, 294 P.2d 378, 382 (1956) (emphasis
18 added). As the *Simms* court noted, "fair value" focuses the Commission's analysis on the "time of
19 inquiry." *Id* at 151, 153, 294 P.2d at 382, 383. Other Arizona cases also recognize that the fair value
20 concept is related to the "time of inquiry." See *Arizona Corp. Comm'n v. Arizona Public Service Co.*,
21 113 Ariz. 368, 370, 555 P.2d 326, 328 (1976) (stating that utility is entitled to reasonable return on
22 the fair value of its properties at time that rate is fixed); *Arizona Corp. Comm'n v. Arizona Water Co.*,
23 85 Ariz. 198, 202, 335 P.2d 412, 414 (1959) (stating that fair value is to be determined as of time of
24 inquiry when determining a utility's rate base and rate of return thereon); *Consolidated Water Utils.*,
25

1 *Ltd. V. Arizona Corp. Comm'n*, 178 Ariz. 478, 482-83, 875 P.2d 137, 141-42 (App. 1993) (stating
2 that rates are based on value of corporation's properties at time rate is fixed).

3 The underlying policy for establishing rates by using historic cost-of-service principles
4 instead of forecasts was articulated by RUCO witness Hill, who acknowledged that it is not unusual
5 for the relationship between the number of customers and the amount of utility plant necessary to
6 serve customers to vary after rates are set. (Tr. at 2148). Mr. Hill stated the following:

7 But my point arguing against the company's position is that *we don't need to stuff*
8 *all those costs in the current rate case because we don't know what those costs*
9 *are.* And I don't know of any utility, regulatory body that lives completely in the
future and tries to discern what the relationship, regulatory relationships are in the
future.

10 (Tr. at 2149 (emphasis added); *see also* Tr. at 2150-51). In short, there are both legal and policy
11 considerations that support the use of an historic adjusted cost-of-service test year as the basis for
12 establishing rates. The Commission should not depart from those principles in this matter.

13 **B. The projections provided by APS in this case are not helpful and should be**
14 **disregarded.**

15 APS has prepared various financial projections that purport to establish APS' financial ratios
16 for 2007, 2008, and 2009 under APS', Staff's, and RUCO's proposals, respectively. APS claims that
17 these forecasts show that, from a quantitative view, APS will not meet the required credit metrics to
18 maintain an investment grade credit rating under either the Staff or RUCO proposals.

19 The Arizona Constitution entrusts the Commission with exclusive authority over all matters
20 related to ratemaking. *See Arizona Corporation Comm'n v. State ex rel. Woods*, 171 Ariz. 286, 292,
21 830 P.2d 807, 813 (1992). Although the Commission is not required to use APS' projections as the
22 basis for setting rates, it may certainly consider such information if the Commission were to
23 determine that the information is helpful. In the context of this proceeding, however, the financial
24 projections provided by APS are not helpful and should be disregarded.

25

1 First, APS' projections have been prepared on a *total company* basis. (Dittmer Supplemental
2 Test., hereinafter referred to as "Dittmer Supplemental", Ex. S-39 at 7). These forecasts of "total
3 company operating results" include APS' FERC-regulated transmission operations. *Id.* Although
4 these FERC-regulated assets are normally not relevant to retail rate proceedings, the Company's use
5 of projections prepared on a total company basis makes them so, because they would include the
6 effects of any "under-earning" on the Company's transmission assets. *Id.*

7 APS witness Wheeler acknowledged that APS is planning on filing a transmission rate case at
8 FERC, (Tr. at 351), thus affirming that APS believes that it is currently under-earning on its
9 transmission investment. According to Staff witness Dittmer's rough calculations, it appears that
10 some fairly significant amount of transmission rate relief is justified, and thus at least part of APS'
11 "total company" earnings shortfall is apparently caused by under-earnings on the Company's
12 transmission assets—operations that are regulated by FERC, not by the Commission. (Dittmer
13 Supplemental at 9). Reliance on "total company" financial metrics that are known to include an
14 earnings shortfall from "non-jurisdictional" business operations is not an accurate measure by which
15 to set rates.

16 Importantly, in a FERC transmission rate proceeding, FERC will not examine whether state
17 retail rates have remedied any earnings shortfall related to transmission investment. *Id.* at 9-10.
18 Instead, FERC will conclude that the Commission's retail rates were established to allow the
19 Company to recover its *retail cost-of-service* on a stand-alone basis and will then proceed to evaluate
20 the need for *transmission rate relief* on a stand-alone basis. *Id.* Furthermore, Decision No. 67744
21 creates a transmission cost adjustor, which APS may use outside the context of a rate case to pass
22 through to retail customers the costs of transmission rate increases. *Id.* at 9.

23 APS would have the Commission remedy any earnings shortfall on its FERC-regulated assets
24 through its so-called "attrition adjustments" that it builds upon its "total company" earnings and
25 coverage ratios shortfall. *Id.* This result would very likely lead to double recovery with Arizona

1 ratepayers paying for the same alleged earnings shortfall once through retail rates and again through
2 FERC transmission rates. This result is hardly fair and serves as an example of the problems inherent
3 in relying on unaudited "total company" forecasts presented comparatively late in the case.

4 In addition, because APS submitted these projections so late in the proceeding, they have not
5 been subjected to the full rigors of a rate case audit and are therefore unreliable. An examination of
6 the procedural schedule in this case will serve to illustrate this point. APS' rate application was filed
7 on January 31, 2006; thereafter, Staff and interveners were allowed approximately 199 days to
8 prepare direct testimony. (April 5, 2006 Procedural Order, Dkt. No. E-01345A-05-0816). During
9 this period of time, Staff issued approximately 630 data requests, reviewed the Company's schedules,
10 testimony, and discovery responses, and conducted interviews and on-site inspections. Because APS'
11 current rate request was based upon an adjusted historic test year cost-of-service, the vast majority of
12 Staff's discovery and analysis was focused on "annualized" and "normalized" historic operating
13 results. As a result of Staff's discovery and audit, Staff identified numerous adjustments to the
14 Company's adjusted historic test year cost-of-service, several of which have been conceded by the
15 Company. Very little discovery or analysis was directed to the Company's post-test-year projections;
16 for again, the Company's projections were *not* the basis of its request for rate relief.

17 APS' rebuttal testimony, which shifted APS' focus from traditional cost-of-service to
18 financial forecasts, was filed on September 15, 2006; thereafter, Staff and interveners were allowed
19 approximately 12 days to prepare surrebuttal testimony. Less than two weeks is woefully inadequate
20 to conduct the necessary discovery and to evaluate issues and related data presented for the first time
21 in rebuttal. (See Tr. at 4197-99). As Staff witness Dittmer explained, auditing forecasts is a complex
22 undertaking that is susceptible to as much dispute as any typical rate case issue. (See Tr. at 4192-95).
23 Even with only limited time and data, Staff has pointed out in surrebuttal and supplemental testimony
24 significant problems in the presentation of the Company's forecasts.

1 **C. Staff's audit shows that APS' current rates appropriately recover the Company's**
2 **non-fuel costs.**

3 APS claims that the cost of customer growth is greater than the revenues generated by that
4 growth, thereby causing the Company's rates to be inadequate. (APS' Br. at 12-13). This claim is
5 not supported by the evidence.

6 ***1. Transmission Costs.***

7 First, as discussed earlier, it is important to recognize that transmission cost recovery is a
8 matter regulated by FERC. Therefore, if APS believes that its current transmission rates do not
9 adequately recover its FERC-jurisdictional cost-of-service, APS should pursue transmission rate
10 relief at FERC. If FERC were to grant APS' request, the Company would be able to pass on the
11 transmission rate increase to retail customers through its transmission cost adjustor. (See Dittmer
12 Supplemental at 9).

13 ***2. Capacity Costs.***

14 Next, it is important to review the structure of the *existing* PSA as it relates to APS' recovery
15 of its incremental generation costs. Demand charges are often excluded from adjustor mechanisms
16 because growth in retail sales will often be available to offset the incremental demand costs incurred
17 to serve new load. (Dittmer Direct Test., hereinafter referred to as "Dittmer Direct", Ex. S-37 at 11).
18 APS' existing PSA, however, permits APS to pass through not only energy charges but also demand
19 charges. (Dittmer Surrebuttal at 11). The purchased capacity paid for through the demand charges
20 replaces the need to build generating capacity that would otherwise be required to meet customer
21 growth. *Id.* APS' significant reliance on purchased power contracts to meet its significant growth, in
22 conjunction with its PSA, provide great assurance that there is no significant earnings attrition for
23 APS' "production function" investment.

24 Therefore, any attrition related to production costs (generation) is significantly addressed
25 through the recovery of demand charges in the PSA, and growth in retail margins is available to a

1 much larger extent to meet cost increases related to growth in distribution plant and to recover cost
2 increases caused by inflation. *Id.* at 12. This feature of APS' existing PSA significantly undermines
3 APS' claim that it will suffer attrition. Furthermore, party is seeking to amend this feature of APS'
4 PSA in this proceeding.

5 **3. *Distribution and Other Costs.***

6 APS contends that rate relief related to fuel and purchased power recovery will not be
7 adequate to allow it to avoid a credit rating downgrade. Staff, by contrast, believes that APS' need
8 for rate relief is driven by the under-recovery of fuel costs. (Tr. at 4197-99). This conclusion is
9 supported by the results of Staff's rate case audit. *Id.* at 4178-80, 4197-99.

10 Staff's audit shows that, except for fuel costs, rates have been adequate to cover non-fuel
11 items. *Id.* at 4178-80. Staff's prefiled surrebuttal position, for example, includes an increase of
12 \$193.5 million for fuel costs and an offsetting *decrease* of \$2 million for non-fuel items. *Id.* at 4179.
13 RUCO's surrebuttal position, although not identical to Staff's, shows an increase of \$280 million for
14 fuel costs and a decrease of \$69 million for non-fuel items. *Id.* Thus, the two parties who
15 customarily conduct thorough rate case audits have concluded that existing rates adequately recover
16 the Company's non-fuel costs. (See Dittmer Surrebuttal at 19). Contrary to APS' claim, there is
17 ample and credible evidence that, on a "normalized" basis, APS is *not* experiencing attrition on its
18 ACC-jurisdictional non-fuel cost of service.

19 **4. *Rate relief that addresses the Company's rising fuel costs is sufficient relief***
20 ***at this time.***

21 To summarize, if the source of APS' alleged under-earnings is its transmission rates, APS
22 may seek rate relief from FERC and may pass through to its retail customers any increases in
23 transmission rates through its transmission cost adjustor. Increases in capacity costs due to customer
24 growth are fully addressed by the structure of APS' PSA, which includes the recovery of demand
25 charges. Finally, the Staff rate case audit in this matter shows that, outside of fuel and purchased

1 power costs, APS' cost of service has been—and continues to be—adequately recovered within
2 existing base rates. (Dittmer Surrebuttal at 19).

3 That leaves the recovery of fuel costs, which Staff's recommendations have generously
4 addressed. Although the Company's rate application is premised upon a test year ending September
5 30, 2005, Staff accepted the Company's proposal to establish the base cost of fuel and purchased
6 power by reference to a forecast of calendar year 2006. (Antonuk Direct Test., hereinafter referred to
7 as "Antonuk Direct", Ex. S-28 at 33; Antonuk Surrebuttal Test., hereinafter referred to as "Antonuk
8 Surrebuttal", Ex. S-29 at 2-10). Staff believes that its recommended base cost for fuel and purchased
9 power is reasonable, especially in conjunction with Staff's proposed PSA.

10 Staff has recommended a number of changes to the PSA, such as the addition of the forward
11 component and the elimination of various existing features, such as the 90/10 sharing mechanism, the
12 \$776 million cap, and the 4 mil bandwidth. (Antonuk Direct at 33, 37; Antonuk Supplemental at 2-
13 8). Staff believes that these modifications will minimize the possibility for large deferrals in the
14 future.

15 Finally, Staff believes that the rating agencies should recognize that the Commission's actions
16 both this year and last show a substantial degree of regulatory support. A review of the
17 Commission's recent decisions regarding APS is instructive:

- 18 1) Decision No. 68437 moved up the adjuster reset from April 1, 2006 to
19 February 1, 2006. The reset date was also modified to February 1st for all
20 subsequent resets. In addition, the \$776 million cap was stayed pending
21 the completion of APS' current rate case.
- 22 2) Decision No. 68685 approved an interim surcharge of 7 mils in order to
23 address APS' 2006 under-recoveries of fuel and purchased power costs.
- 24 3) Decision No. 69184 approved the continuation of the interim 7 mil
25 surcharge until the completion of the rate case.

24 In the context of these decisions, it is difficult to consider Staff's proposed modifications to the PSA
25 as anything but a concerted regulatory response to ensure that APS will have an opportunity to timely

1 recover its fuel and purchased power costs. Staff also believes that the rating agencies should view
2 the modified PSA, if adopted by the Commission, as yet another sign of regulatory support.

3 5. *APS' November 28, 2006 response to Chairman Hatch-Miller's letter is not a*
4 *basis for concluding that earnings attrition is occurring due to customer*
 growth.

5 Late in the proceeding, APS produced a letter that is designed to demonstrate that it costs
6 more to serve a new APS customer than an existing APS customer. The letter was produced after the
7 cut-off date for discovery and thus Staff has not had an opportunity to review the data, calculations,
8 or assumption underlying the letter. Nonetheless, Staff witness Dittmer noted the following
9 shortcomings:

- 10 1) The document appears to have examined growth in *gross* plant in service
11 amounts to serve customers. It fails to capture the fact that, for instance,
12 *net* production plant has actually been declining in most years. The
 growth in the depreciation reserve serves to offset the higher costs of new
 gross plant added to serve new customers.
- 13 2) The document fails to recognize that many expenses remain relatively
14 fixed notwithstanding growth in customers and sales. Thus, the
15 “economies of scale” have not been considered anywhere as an “offset” to
 the purported attrition occurring with new customer growth.
- 16 3) There can often be other “offsets” to serving new customers, such as the
17 post test year federal income tax savings that will occur with the increase
18 in the production tax credit beginning in 2007. No party has
 recommended including these savings within the adjusted test year cost of
 service.
- 19 4) The Company's assumption of the marginal cost of debt underlying new
 plant investment is significantly overstated—by over 100 basis points.
- 20 5) The document does not distinguish which gross plant additions are being
21 added to achieve operational savings. It is reasonable to assume that at
22 least a portion of the projected plant additions are being constructed to
 achieve operating expense savings—which are not included within the
 Company's response.

23 (Tr. at 4174). In short, the data contained in this letter have not been subjected to
24 scrutiny. However, even without the benefit of discovery and analysis, Staff has pointed
25

1 out many concerns—if not outright flaws—in the document. It should be rejected as a
2 basis for supporting the Company’s attrition request.

3 **II. COST OF CAPITAL**

4 There are three steps to determining a utility’s cost of capital in a rate proceeding:
5 1) determining the appropriate capital structure, 2) determining the appropriate cost of debt, and 3)
6 estimating a reasonable cost of equity. As between Staff and APS, the first two steps of this inquiry
7 are not in dispute. The third step—determining the appropriate cost of equity—is the cost of capital
8 issue that remains at issue.

9 To estimate the cost of equity, Staff used three recognized methodologies: the Discounted
10 Cash Flow Model (“DCF”), the Capital Asset Pricing Model (“CAPM”), and the Comparable
11 Earnings Method (“CE”). (Parcell Direct Test., hereinafter referred to as “Parcell Direct”, Ex. S-8 at
12 3-4). Each of these methods was applied to two different sets of proxy groups: one developed by
13 Staff witness Parcell and another developed by APS witness Avera. *Id.* Based upon this analysis,
14 Staff witness Parcell concluded that APS’ cost of equity falls within a range of 9.5–10.75 percent. *Id.*
15 at 4. Staff recommended the mid-point of this range, 10.25 percent, as the cost of equity for APS.
16 (Parcell Direct at 4; Tr. at 3251-52).

17 APS claims that Staff’s recommendation suffers from a “downward bias” that results from
18 “flawed analysis.”¹ (APS’ Br. at 21-22). APS also attempts to cast doubt upon the validity of the
19 DCF method, alleging that certain limitations of the DCF model make it unsuitable for capturing the
20 long-term expectations for the utility industry. *Id.* at 20. By contrast, Staff believes that the DCF
21 model is a useful tool in estimating the cost of equity.

22 First, it is undisputed that regulatory commissions across the country continue to consider and
23 rely upon the DCF model. (Tr. at 3236-37). Indeed, each of the three cost of capital witnesses in this
24

25 ¹ Staff witness Parcell discusses in detail these alleged errors and explains why these criticisms are without merit. (See Parcell Surrebuttal Test., hereinafter referred to as “Parcell Surrebuttal”, Ex. S- at 5-10).

1 proceeding performed a DCF analysis, although each assigned a different degree of reliance to his
2 DCF results. While RUCO witness Hill relied heavily upon his DCF results, APS witness Avera
3 almost entirely discounted his DCF results. Staff witness Parcell's analysis, by contrast, represents a
4 sort of middle ground: while Mr. Parcell's cost of equity analysis relies upon his DCF results, he
5 does not rely upon them *exclusively*. (Parcell Direct at 4, 32; Tr. at 3245). Furthermore, although
6 Mr. Parcell's DCF results range from 9.0-10.0, his analysis focused on the upper end of that range,
7 *i.e.*, 9.5-10.0, in order to recognize the additional risk factor posed by APS' current bond rating. (Tr.
8 at 3240, 3259-60). Staff's approach is therefore a measured one, appropriately considering its DCF
9 results along with the results of the other models and the varying degrees of APS' risk. *Id.* at 3259-
10 60.

11 It is worth noting that the DCF results from all three cost of capital witnesses were relatively
12 close. *Id.* at 2168. It is also true that, in this proceeding, the DCF model produced lower cost of
13 equity estimates than that of the various other cost of equity estimation models. The fact that the
14 DCF results are consistently lower than those produced by other models—in and of itself—is not a
15 valid reason to disregard the DCF results, especially when those results are similar among three
16 witnesses who do not necessarily share a common conceptual orientation. (*See* Tr. at 2168).

17 APS argues that, because industry analysts expect lower returns for utilities, the DCF model
18 becomes unreliable. (*See* Tr. at 2169). This contention is disputed on the record. For example,
19 RUCO witness Hill reached a contrary conclusion:

20 We know that the DCF Model is simply the dividends divided by the stock price
21 plus the growth rate. Well, if investors are really bearish on utilities, what will
22 happen? The price will go down....And in that model, dividend over price,
dividend won't change but the price gets smaller. That means that ratio will be
larger and the cost of capital, as indicated by the DCF, will go up.

23 So, Dr. Avera's representation to you that the DCF is unreliable, *i.e.* too low,
24 because investment companies are bearish on utilities is exactly the wrong advice.
25 If investment companies were bearish on utilities, the price would go down, the
dividend would go up, and the DCF would give a high number....

1 *Id.* Staff witness Parcell also disputed the Company's contention that the DCF model contains a
2 downward bias, albeit for somewhat different reasons. In his discussion of the effects of overall
3 economic and financial conditions, he drew the following conclusion:

4 It is apparent that capital costs are currently low in comparison to the levels that
5 have prevailed over the past three decades. In addition, even a moderate increase
6 in interest rates, as well as other capital costs, would still result in capital costs
7 that are low by historic standards. Therefore, it can reasonably be expected that
8 cost of equity models, such as the DCF, currently produce returns that are lower
9 than was the case in prior years.

10 (Parcell Direct at 12; *see also id.* at 9-10).

11 Even aside from the DCF model, APS claims that it has demonstrated the alleged "downward
12 bias" in Staff's cost of equity estimate by reference to various industry benchmarks. (*See* APS' Br. at
13 21). Specifically, APS' brief cites the following sources:

14 [T]he rates of return on common equity authorized electric utilities by regulatory
15 commissions were 10.69 percent for electric utilities in the second quarter of 2006
16 and 10.57 percent for the year as of September 15, 2006. Using the groups of
17 firms identified as most comparable to APS by Mr. Hill and Mr. Parcell, the two
18 groups of firms were authorized on average ROE of 10.89 percent and 10.91
19 percent respectively. Second, Value Line reported as of September 1, 2006, that
20 electric utilities as a whole are anticipated to earn a return of at least 10.5 percent
21 from 2007 through 2011. And Lehman Brothers projected that in 2007 the
22 electric utility industry would be granted allowed rates of return that averaged
23 11.3 percent in order to keep pace with the market as a whole.

24 (APS' Br. at 21 (emphasis added) (citations omitted)). As an initial matter, Staff does not agree that
25 reference to these alleged "benchmarks" is necessarily helpful or relevant to determining APS' cost
of capital. (*See* Parcell Surrebuttal at 4). Setting those concerns aside, however, it is nonetheless
curious that APS would claim that these "benchmarks" somehow undermine Staff's cost of equity
estimate. All except one (11.3) are in the mid to upper tens (10.69, 10.57, 10.89, 10.91, 10.5); for the
most part, they are closer to Staff's estimated cost of equity (10.25) than they are to APS' (11.5).
(*See* Parcell Surrebuttal at 2-3). Furthermore, APS overlooks other evidence in the record that
suggests that APS' own investment advisers expect a return on the broad stock market that is "well

1 below" ten percent. (Tr. at 2054-57). This information is consistent with Staff witness Parcell's
2 conclusion that, due to the current level of capital costs, cost of equity models are likely to produce
3 results that are low by historic standards. (Parcell Direct at 12; Parcell Surrebuttal at 5).

4 One may be tempted to conclude that Staff's recommended cost of equity estimate is identical
5 to that adopted for APS in its last rate case and therefore merely maintains the status quo. Staff
6 witness Parcell, however, explained why this conclusion is incorrect:

7 Q. Your recommendation, sir, of a return on equity of 10.25 percent is the same
8 as the company's allowed rate of return at the present time; correct?

9 A. Yes and no.

10 Q. It's a simple question. Yes?

11 A. It's yes and no, because the rate of return is the overall rate of return. The
12 10.25 percent agreed to in the 2003 case, which was settled in 2005, was
13 based upon a common equity ratio of 45 percent and a cost of debt of 5.8
14 percent. The cost of debt has gone down to 5.4, and the common equity ratio
has gone from 45 percent to 54.5. So the other two components have both
moved [in] [sic] the company's favors since that time. So the maintenance of
10.25 with a lower cost of debt and a higher equity ratio is an improvement.

15 Actually, in the calculation I think it's a—7.8 was the rate of return agreed to
16 last time, and I recommended 8.05. That's 25 basis points higher than total
cost of capital, 25 more basis points than total rate base, and that's real
money.

17 (Tr. at 3285-86).

18 APS also claims that Staff has ignored the principles of *Hope* and *Bluefield*. As discussed
19 earlier, Staff disagrees with APS' assertion that the Commission is legally required to consider
20 financial projections in order to satisfy the principles of *Hope* and *Bluefield*. Nonetheless, a review
21 of Staff's testimony clearly demonstrates that Staff considered these principles in developing its
22 recommendations. (Parcell Direct at 6-8; Tr. at 3258-62, 3265-69, 3273-84). APS also argues that
23 Staff failed to consider the potential impact of its recommendations upon the Company's bond rating.
24 Contrary to APS assertions, Staff witness Parcell clearly considered APS' current ratings as well as
25

1 various rating agency statements in arriving at his recommendation. (Tr. at 3270-711; 3282-88;
2 3291-92; 3294-3303; 3305-06).

3 APS contends that Staff's recommendation is inconsistent with the testimony of Staff witness
4 Rogers, which was filed in a recent case. In his surrebuttal testimony, Mr. Parcell addressed these
5 allegations:

6 [M]y review of Mr. Rogers' testimony reveals to me that our conclusions are very
7 similar. In his testimony, Mr. Rogers recommended, for Paradise Valley Water
8 Company...a return on equity range of 9.6 percent (DCF results) to 10.0 percent
9 (CAPM results) plus a 0.6 percent "upward financial risk adjustment" which was
10 designed to recognize the financial risk associated with the 36.7 percent common
equity ratio of the utility. In the case of Paradise Valley Water, the subject utility
had more leverage and thus financial risk than the proxy group. In the case of
APS, on the other hand, the opposite situation occurs, since APS has a higher
equity ratio and thus less financial risk than the proxy group.

11 (Parcell Surrebuttal at 11). APS cites limited portions of Mr. Rogers' testimony, thereby overlooking
12 the fact that Mr. Parcell's 10.25 percent recommendation for APS is quite comparable to Mr. Rogers'
13 10.4 percent recommendation. *Id.* at 12.

14 Finally, Staff notes that APS' recommended 11.5 percent cost of equity includes an
15 adjustment for flotation costs. Specifically, APS has increased its cost of equity estimate by twenty
16 basis points as a flotation cost adjustment (Parcell Direct at 37). Staff opposes this adjustment. A
17 utility should only be allowed to recover from ratepayers its actual and quantifiable levels of issuance
18 costs. *Id.* APS has not demonstrated that it has actually incurred any issuance costs. *Id.*

19 In addition, the market-to-book ratios of Dr. Avera's electricity distribution group are
20 sufficiently high as to make a flotation adjustment unnecessary and inappropriate, because any
21 common stock issuance would actually increase book value of existing stockholders. *Id.* Finally, the
22 revenue requirement impact associated with APS' flotation cost adjustment is nearly \$8 million
23 annually. *Id.* As Staff witness Parcell noted, this is an excessive level of flotation costs for
24 ratepayers to bear. *Id.*

25

1 In summary, Staff's cost of equity estimate is based upon recognized models that were
2 applied in a measured and reasonable manner. The Commission should therefore adopt Staff's
3 recommended cost of equity for purposes of determining APS' rates.

4 **III. PENSION EXPENSE**

5 As Staff witness Dittmer explained, layering APS' proposed five-year accelerated "catch up"
6 adjustment on top of the FAS 87-determined pension expense, which already incorporates a "catch
7 up" provision, will likely lead to a double or over-recovery of the underfunded pension liability. FAS
8 87 effectively includes a "catch up" provision for situations wherein the trust fund significantly
9 underperforms relative to earlier projections or when other previously expected assumptions change
10 over time. In fact, a significant element of the Staff-proposed FAS 87-determined pension expense
11 consists of such a "noted "catch up" provision. Thus, if rates are established based upon FAS 87-
12 determined pension accruals—as Staff recommends—the presently-calculated shortfall will be
13 recovered over time, albeit not over the accelerated five-year period that APS recommends.

14 In its brief, APS presents a number of arguments in favor of its proposal to accelerate the
15 recovery of pension expense. None of APS' arguments, however, convincingly explains how APS
16 plans to address the regulatory liability that its proposal will create. Staff witness Dittmer described
17 this issue in his testimony:

18 I still have problems with just how the company's plan would even work, how it
19 could mechanically work. *Where are you going to get the cash to refund*
customers?

20 You can see the money going into the trust. No doubt about that. I believe your
21 accountants and Mr. Brandt have testified that if the company's proposal is
22 adopted, you increase the expense for regulatory purposes, you increase the check
that you write to the pension trust. I understand that for the first five years.
That's pretty easy.

23 Now we get ready to refund the customers. *You can't take the money out of the*
trust. You got to take it from someplace else. And the company has already
complained about cash flow problems. This proposal doesn't help anything in the
short run, the five-year period, and it exacerbates the cash flow problems in years

1 6 through 15, in my opinion, from what I've seen so far. I do not know how you
2 cannot create a cash flow problem with this proposal.

3 (Tr. at 4217-18 (emphasis added)). APS' proposal will not improve its cash flow position in the short
4 term, because APS has committed to funding its pension trust with the incremental rate recovery that
5 its proposal would generate. APS' proposal will also worsen its cash flow position in the long term,
6 because APS will have to refund the regulatory liability to its customers. APS' proposal is not in the
7 best interests of either the Company or its customers, and the Commission should therefore reject it.

8 **IV. CASH WORKING CAPITAL**

9 Staff and APS disagree over the cost-of-service elements that should be reflected in the cash
10 working capital calculation. APS contends that both depreciation and deferred taxes generate
11 additional investment that should be reflected in rate base as part of the allowance for cash working
12 capital. (APS' Br. at 42). APS also contends that interest expense should be excluded from the
13 development of a lead-lag study. *Id.* Finally, APS opposes Staff's exclusion from the lead-lag study
14 of the amortized expenses of pre-paid insurance costs and nuclear fuel. *Id.* at 44.

15 A. Depreciation and Deferred Taxes.

16 Both depreciation and deferred taxes are non-cash expenses. Neither requires APS to make a
17 cash outlay in order to meet the day-to-day expenses incurred in providing utility service. APS
18 argues that there is a gap between the time when customers are credited for their payment of these
19 expenses and the time when customers actually pay for them. (APS' Br. at 42). But APS ignores the
20 fact that this "gap" is a phenomenon of regulation. In other words, APS' crediting (through a rate
21 base deduction) of customers' payments of these expenses does not require an actual cash outlay.
22 This point is well illustrated by the arguments set forth in RUCO's brief in this matter:

23 APS' arguments lack merit, as they both are based on the erroneous assumption
24 that a lead lag study and the resulting cash working capital requirement is
25 intended to measure *regulatory* lag. In fact, the purpose of a lead lag study is to
 measure the period of time between when service is rendered and when cash is
 received or dispersed.

1 APS claims that depreciation should be included in cash working capital because
2 “rate base is reduced during the benefit period when the expense is incurred,” but
3 depreciation is recorded some 37 days before APS recovers the revenues related
4 to depreciation. However, the premise on which APS’ argument is based is
5 flawed. Rate base is *not* reduced each month when depreciation is booked.
6 Rather, rate base is a purely regulatory concept, and is recomputed only at the
time of a rate case. Thus, when APS books depreciation expense in October
2006, it does not result in an immediate decrease to rate base and does not result
in a lower revenue requirement in November 2006. Instead, the revenue APS
collected in December 2006 was based on the undepreciated plant levels as of
December 2002, the end of the test year in APS’ last rate case.

7 (RUCO’s Br. at 10-11 (emphasis in original) (citations omitted)).

8 Furthermore, assuming for purposes of argument that the lead-lag study were expanded to
9 analyze the collection of “depreciation expense,” it should also symmetrically and equitably be
10 expanded to consider the lag in the payment of construction expenditures. If the study were thus
11 expanded, plant in service/rate base would be reduced for the construction expenditures recorded as
12 “gross plant in service” at test-year end that have not yet been “paid for” by APS. Stated simply,
13 APS cannot selectively choose to expand the study to consider “non-cash” expenses, such as
14 depreciation and deferred income tax expense, unless it is willing to consider “offsets” to such
15 components, such as test-year end plant in service not yet “paid for” by APS.

16 In considering this issue, it is helpful to recall the definition of cash working capital: cash
17 working capital is defined as the amount of cash needed by a utility to pay the day-to-day expenses
18 incurred in providing service as compared to the timing of the utility’s collection of revenues for
19 those services. (Dittmer Direct at 33, 36). Therefore, the items that appropriately fall within the
20 scope of a lead-lag study are those transactions that relate to the *day-to-day payment of expenses*
21 *incurred* in providing utility service. *Id.* at 33, 36-37. Neither depreciation expense nor deferred
22 income tax expense meets this definition; therefore, the Commission should exclude these items from
23 the calculation of cash working capital.

24 ...

25 ...

1 **B. Interest Expense.**

2 The ratemaking formula provides for the recovery of interest expense. (Dittmer Direct at 43).
3 Ratepayers pay for service on a monthly basis, yet the periodic payment of interest expense to debt
4 holders typically occurs at somewhat extended intervals, *i.e.*, quarterly or semi-annually. Fairness
5 requires the lead-lag study to recognize that the Company has the use of these funds for the extended
6 period between their collection from ratepayers and the Company's payout of interest to debt holders.
7 *Id.* For these reasons, interest expense should be included in the lead-lag study.

8 APS argues that, if the lead-lag study considers interest expense, then it should also consider
9 the lag in the receipt by equity investors of their return. (APS' Br. at 43). In fact, as Mr. Dittmer
10 noted in his direct testimony, common stockholders are typically paid dividends quarterly after the
11 company has "earned" such return. If the lead-lag study were to be expanded to consider the lag in
12 the payment of dividends, the result would be an even larger rate base deduction, not a smaller one as
13 suggested by APS. Thus, Staff's approach of only including interest expense in the lead-lag study—
14 consistent with all Commission decisions on this issue for at least twenty years—is, if anything,
15 conservative and should be upheld.

16 **C. Amortized Prepaid Insurance and Nuclear Fuel Expenses.**

17 Staff has excluded amortized prepaid insurance and amortized nuclear fuel expenses from the
18 lead-lag study because they are non-cash expenses. Accordingly, they should be excluded from the
19 lead-lag study for the same reasons that other non-cash expenses should be excluded. (*See* Dittmer
20 Direct at 33-42).

21 **D. Arizona Precedent.**

22 Finally, it is worth noting that the Commission has unambiguously concluded that non-cash
23 items, such as depreciation expense and deferred tax expense, should be excluded from lead-lag
24 studies. The Commission has also concluded—just as unambiguously—that interest expense should
25 be included in lead-lag studies. (*See* Dittmer Direct at 28-29). Furthermore, the Company has not

1 offered any new arguments to explain why these issues should be reconsidered. Staff recommends
2 that the Commission follow its established precedent and adopt the adjustments to APS' lead-lag
3 study proposed by Staff.

4 **V. INVESTMENT TAX CREDITS**

5 The investment tax credits ("ITCs") at issue in this proceeding result from APS' filing of
6 amended federal income tax returns. (*See* Dittmer Direct at 100). Specifically, these prior federal
7 income tax returns were amended in order to claim additional ITCs related to plant that had been
8 constructed in the mid to late 1980s. *Id.* During the discovery phase of this proceeding, APS
9 described the tax return associated with this issue as expected and imminent. *Id.* at 103.

10 Staff has proposed that the Commission recognize as a rate base offset all of the unamortized
11 ITC balance related to plant not fully depreciated. (Dittmer Surrebuttal at 43). The description of
12 and rationale for this adjustment are fully addressed in the testimony of Staff witness Dittmer. (*See*
13 Dittmer Surrebuttal at 43-45).

14 In its brief, APS implies that the Commission has disposed of this issue in a prior decision.
15 (*See* APS' Br. at 45). Decision No. 58644, which adopted a 1994 settlement agreement, provided
16 that the then-remaining (*i.e.*, as of 1994) unamortized ITCs related to years before 1991 would be
17 fully amortized below the line over the subsequent five years. (*See* Dittmer Direct at 105). APS now
18 argues that the Commission's 1994 decision, which addressed then-remaining unamortized ITCs,
19 somehow anticipated and dealt with the treatment of the ITCs at issue in this proceeding,
20 approximately twelve years later.

21 Staff witness Dittmer anticipated APS' argument in his direct testimony:

22 *It is possible that if these recently claimed ITCs had been known and quantified at*
23 *the time of the 1994 agreement that such ITCs would have simply been lumped in*
24 *with other unamortized ITCs on APS' balance sheet existing at that time and*
25 *amortized over the same five year period as other ITCs existing at that time.*

1 *In light of all the uncertainty surrounding how these ITCs might have been*
2 *recognized in prior regulatory proceedings, the di minimus amount at issue, as*
3 *well as all the other arguments for and against ratepayer participation in benefits*
4 *from the transaction, I am recommending that the costs to achieve the ITC saving*
5 *be deducted from the total revenue requirement benefits expected to be realized. I*
6 *am proposing that one-half of the remaining benefits or savings resulting from the*
7 *transaction be used as a rate base offset—as had been the precedent for ITCs prior*
8 *to 1994.*

9 *Id.* at 105-06 (emphasis added)). Staff witness Dittmer subsequently amended his recommendation
10 somewhat in order to avoid any possible Internal Revenue Code normalization violations—the *only*
11 argument raised by APS on this issue within its rebuttal testimony.

12 As a result of the revision to Staff's original adjustment to eliminate a possible violation of
13 IRC normalization requirements, Staff has recommended in surrebuttal that far less than half of the
14 newly-determined ITC savings be allocated to ratepayers. (Dittmer Surrebuttal at 43). Thus, Staff's
15 surrebuttal testimony recognizes the uncertainty surrounding possible IRC normalization violations
16 and proposes a regulatory treatment that is very generous to the Company but nonetheless provides
17 some benefit to ratepayers. Staff's proposal on this issue is reasonable and should be adopted.

18 **VI. BARK BEETLE REMEDIATION**

19 In its brief, APS correctly notes that the disputes regarding recovery of bark beetle
20 remediation costs relate to the time period over which the Company may defer these costs. (APS' Br.
21 at 53). APS contends that the plain meaning of Decision No. 67744 authorizes the Company to defer
22 bark beetle remediation costs beginning January 1, 2005, a full three months before that decision was
23 issued. APS' construction of Decision No. 67744 requires a retroactive application of that order.
24 APS, however, has not—because it cannot—identify any provision in that decision that *expressly*
25 indicates that the Commission intended *retroactive* application.

26 APS relies upon the portion of Decision No. 67744 that allows it to defer “reasonable and
27 prudent direct costs of bark beetle remediation that exceed the *test year* levels of tree and brush
28 control.” Using the cited text, APS goes on to argue that “the language indicates that a full year of

1 cost recovery was intended.” *Id.* at 54. The plain and simple fact is that APS has clearly deferred
2 even more than a full year of bark beetle remediation costs—beginning in April 2005 and as
3 projected through the end of 2006.

4 Ultimately, the Commission can tell the parties what it intended within the language of
5 Decision No. 67744. As Staff witness Dittmer testified, “in all my years of negotiating and reviewing
6 the impact of accounting deferral orders, I do not ever recall an order being applied retroactively from
7 the implementation date of the order *unless explicitly set forth within the order.*” (Dittmer
8 Surrebuttal at 41 (emphasis added)). It is noteworthy that APS has not disputed this claim, nor has it
9 provided any citation to suggest that it has ever observed the retroactive application that it seeks in
10 this case.

11 **VII. SUNDANCE UNITS**

12 APS has included in its cost of service the operations and maintenance expense associated
13 with its recently acquired Sundance Combustion Turbine Units (“Sundance”). Staff opposes the
14 recovery in rates of certain estimated Sundance O&M expenses that indisputably will not actually be
15 incurred for many years into the future. (Dittmer Direct at 95).

16 Staff acknowledges that APS generally normalizes maintenance costs for its mature
17 generating units by calculating a multi-year historical average of such costs, adjusted for inflation
18 over time, to arrive at a normalized level of maintenance expense. *Id.* at 98. APS claims that this
19 method is akin to a “long-accepted Arizona regulatory practice” and that Staff has not offered any
20 reason to reject it. (APS’ Br. at 56). This criticism is inaccurate. Staff has specifically and
21 repeatedly identified the rationale underlying its Sundance adjustment: the maintenance costs in
22 question will not actually be incurred for many years into the future—well past the time when rates
23 set in this proceeding are likely to be in effect. (Dittmer Direct at 95-100).

24 APS also claims that Staff’s approach to PWEC maintenance costs is inconsistent with its
25 approach to Sundance maintenance costs. Specifically, APS notes that Staff has not objected to APS’

1 proposal to recover one-twelfth of its twelve-year forecast of maintenance expenses for PWEC. APS
2 fails to note, however, that it has used a unique approach for normalizing Sundance maintenance
3 expense. Specifically, APS reaches far into the future to incorporate planned Sundance maintenance
4 expenditures when developing its Sundance normalization adjustment. For the PWEC units, APS
5 admittedly uses a twelve-year forecast, but importantly, APS is already incurring a portion of such
6 maintenance expense. The PWEC situation contrasts factually with the Sundance situation, wherein
7 again Staff notes that the maintenance expenditures will not occur until many years in the future.

8 In testimony, Staff witness Dittmer described the risk for double recovery that APS' proposal
9 presents. *Id.* at 98-99. If this proposal were adopted, the Commission creates the risk that ratepayers
10 will pay for these costs both now and then again through future rates. (Dittmer Direct at 99; Tr. at
11 4224-25). If the Commission were to accept APS' proposal, it should at least require APS to
12 recognize as a current period expense amounts collected in rates for Sundance's non-routine
13 maintenance expense and to concurrently establish a regulatory liability on its balance sheet.
14 (Dittmer Direct at 99; Tr. at 4226). This accounting treatment will ensure that ratepayers will not be
15 charged twice for the same expense. (*See* Dittmer Direct at 99-100).

16 VIII. LOBBYING EXPENSES

17 Pursuant to the Federal Energy Regulatory Commission ("FERC") Uniform System of
18 Accounts ("USOA"), utilities are required to record lobbying costs below the line, where there is a
19 presumption of non-recovery. (Dittmer Direct at 114-15). In this case, contrary to USOA guidelines,
20 APS charged a number of its lobbying costs above the line to administrative and general expense
21 accounts, and these lobbying costs were therefore included in its proposed test year cost of service.
22 *Id.* at 116. As the Company itself states in its post hearing brief, "[t]he Company itself already
23 allocated certain costs between 'below-the-line' lobbying activities for which the Company is not
24 seeking recovery and 'above-the-line' Public Affairs activities" (APS' Br. At 69 (emphasis
25

1 added)). It is inappropriate for the Company to disregard the requirements of the USOA by recording
2 these costs in this way.

3 APS is *required* to record all lobbying costs below-the-line, and its disregard of this
4 requirement should be disturbing. (Dittmer Direct at 114). Recording lobbying expenses properly,
5 *i.e.*, below-the-line, does not preclude APS from seeking cost-of-service recognition for them in this
6 or subsequent rate cases. *Id.* at 117. It does, however, require APS to propose a specific adjustment
7 to its operating income in order to seek rate recovery of these costs. *Id.* Proper accounting of these
8 costs will ensure that expenses that are presumed to fall outside of the Company's cost-of-service are
9 not hidden within inappropriate accounts, thereby placing the burden upon Staff auditors to uncover
10 them. For these reasons, the Commission should specifically recognize that APS has failed to
11 recognize the requirements of the USOA and should order APS to appropriately comply with these
12 requirements.

13 APS also argues that the Commission should permit it to recover certain lobbying expenses in
14 rates. APS cites certain previous Commission orders to support the argument that the Commission
15 has previously allowed lobbying expenses in rates if the utility can demonstrate that the lobbying
16 benefits ratepayers. The cases that APS cites, however, address membership dues or trade industry
17 dues and are therefore not precisely on point.

18 Staff contends that lobbying expenses should be disallowed as a matter of regulatory policy.
19 (Tr. at 4230-34). Staff witness Dittmer explained the reasons for this well established policy:

20 [U]tilities are unique in that they have a certain required service, a regulated
21 service that's not provided by other providers. They wield great power in that
22 respect. And, therefore, as a matter of regulatory policy, I don't think that they
23 should be encouraged to lobby by including that expense in the cost of service.

24 Now, admittedly some lobbying arguably helps ratepayers, but to try and
25 distinguish what is good lobbying versus bad lobbying becomes a very difficult
26 task. And even so-called good lobbying for ratepayers sometimes comes at a cost
27 to other taxpayers, other constituents, other contractors.

28 So just as a matter of regulatory policy, I say just say no to lobbying expenses
29 included in the cost of service.

1 (Tr. at 4231). The Commission should follow this established policy and exclude lobbying expenses
2 from APS' rates.

3 IX. INCENTIVE COMPENSATION

4 APS claims that the incentive compensation issue should focus upon whether APS employee
5 compensation—as a whole—is reasonable, not how that compensation is determined. (APS' Br. at
6 74). This argument overlooks the fact that the means of determining compensation has a substantial
7 effect upon employee behavior and management decisions.

8 Ratepayers should not have to bear costs that do not have any associated ratepayer benefit. It
9 is undeniable that APS' stock-based incentive compensation plan is aligned with stockholder—not
10 ratepayer—interests. (Dittmer Direct at 107-08). The specific terms of APS' stock-based incentive
11 compensation programs are driven by the financial performance of Pinnacle West, rather than the
12 operational performance of APS as a public utility. *Id.* at 108. Enhanced earnings levels can
13 sometimes be achieved by short-term management decisions that are not in the interests of ratepayers.
14 *Id.* at 111. The Commission should therefore adopt Staff's proposed disallowance of the costs of
15 APS' stock incentive compensation program.

16 APS witness Mark Gordon testified in support of APS' overall compensation program,
17 including its stock compensation plan. The alleged benefits of the Company's stock compensation
18 plan identified by Mr. Gordon are cited within the Company's brief. (APS' Br. at 74). Mr. Gordon's
19 testimony in a recent Puget Sound Energy, Inc. ("Puget") rate case contained observations about
20 incentive plans that are based entirely upon financial performance. Specifically, Mr. Gordon's Puget
21 testimony contains the following statements:

22 PSE's Goals and Incentive program is more detailed in the specificity of financial
23 and non-financial goals and better communicates the linkage of goal attainment
24 with incentive award opportunity than the majority of broad-based incentive plans
25 at other companies. *Very often, broad-based incentive plans are solely tied to
company earnings with no variation for business unit or team performance, and
no link to customer and/or service reliability objectives. These types of plans act*

1 *more as an end of year” bonus” than a motivational “pay for performance”*
2 *system driving specified behavior.”*

3 (Ex. S-4 at 7 (emphasis added)). Mr. Gordon’s disparaging remarks about incentive compensation
4 plans “solely tied to company earnings” perfectly describe APS’ stock compensation plan.

5 Also of interest, Mr. Gordon’s Puget testimony emphasizes that Puget has a stock-based long
6 term incentive plan using common shares of Puget Energy stock, similar to the APS stock
7 compensation plan at issue in this proceeding. However, Mr. Gordon’s Puget testimony
8 acknowledges that Puget’s stock-based compensation is funded fully by shareholders and is not
9 included within Puget’s proposed cost of service. Mr. Gordon’s testimony from the Puget case
10 appears to support Staff’s incentive compensation adjustment.

11 **X. PROPERTY TAX EXPENSE**

12 APS argues that the Commission should reject RUCO’s property tax adjustment, claiming that
13 rates set in this proceeding should be established by considering property tax expense amounts
14 expected to be paid in 2007. Staff continues to support RUCO’s property tax adjustment over APS’
15 objections.

16 In support of this adjustment, Staff notes that APS proposes to reflect *only 2007 property tax*
17 *expense*. Throughout this proceeding, APS has continually reminded this Commission of the high
18 growth in its service territory in sales. APS, however, fails to propose any increase in margins to the
19 2007 time period that would offset an increase in projected property tax expense.

20 Furthermore, APS is inconsistent in its position on property tax expense versus income tax
21 expense. Specifically, APS opposes an adjustment to increase the production tax credit that is *known*
22 *to occur in 2007* that will result in lower federal income tax expense—by an amount that is nearly
23 identical to the amount of the RUCO property tax adjustment. Stated simply, APS cannot credibly
24 argue for 2007 property tax expense levels while simultaneously arguing against known reductions in
25

1 federal income taxes. RUCO's proposed property tax adjustment is reasonable and should be
2 accepted.

3 XI. PALO VERDE ISSUES

4 A. APS documents and NRC evaluations are virtually the only source for
5 determining the level of the Company's knowledge about the details of its
6 performance.

7 During 2005, the Palo Verde Nuclear Generating Station ("Palo Verde") experienced a total
8 of eleven planned and unplanned outages. Of these outages, Staff identified four as imprudent.
9 (GDC Report, hereinafter referred to as "GDS Report", Ex. S-45 at 2). APS is therefore responsible
10 for these outages, and ratepayers should not have to bear their costs.

11 The Company claims that Staff's analysis improperly relies upon NRC documents, INPO
12 evaluations, and Company root-cause reports. The Company contends that these sources analyze
13 Palo Verde's operations with the benefit of hindsight and are therefore irrelevant to determining
14 whether APS was imprudent. However, as Staff witness Jacobs testified, these reports provide vital
15 contemporaneous evaluations by the respective entities that produced them. (Jacobs Surrebuttal
16 Test., hereinafter referred to as "Jacobs Surrebuttal", Ex. S-48 at 15). Reports such as these are
17 routinely considered in prudence evaluations by a variety of regulatory commissions. *Id.*

18 FERC has relied on both NRC and company documents in determining the prudence of
19 nuclear plant outages:

20 The Company is correct that these NRC findings do not translate directly into a
21 finding of imprudence from an economic regulatory perspective... But at some
22 point, surely, a great number of NRC negative comments about a particular
23 plant's management and operations and admissions by Company managers to
24 such conduct become inconsistent with the notion of a prudently managed nuclear
25 plant from any perspective, including economic regulation... [and] these negative
26 comments from nuclear safety regulators ... also provide evidence that can and
27 should be used in reaching an economic regulatory judgment about the prudence
28 of management conduct.

29 While, considered alone, the admissions of the Company managers about their
30 shortcomings and weaknesses are not quite a confession of imprudence.... They

1 nevertheless provide strong evidentiary support for a finding of imprudent
2 management.... It would take tortured logic, indeed, to conclude that the NRC's
3 hyper-critical comments about the Company's management of the plant and the
4 Company's own admission of significant failures and shortcomings described in
5 this report are consistent with reasonable and prudent managerial conduct from
6 either a safety or economic regulatory perspective.

7 *Connecticut Yankee Power Co.*, 84 FERC ¶ 63, 009, 65, 110-11 (1998). Clearly, it is reasonable to
8 review documents prepared by the Company or the NRC to determine what the Company knew when
9 the relevant events occurred.

10 These evaluations provide a picture of the operations and performance of Palo Verde going
11 into 2005. By all accounts, as Palo Verde entered 2005, it was already experiencing a decline in
12 performance, and over the course of 2005, Palo Verde's performance continued to decline. (Jacobs
13 Surrebuttal at 2-3). The result of the INPO review was a level 3 rating, a mark that the Company
14 concedes does not reflect well on the plant's performance. (Tr. at 5161-5162). In response, the
15 Company initiated a program to improve its performance, the Performance Improvement Plan
16 ("PIP").

17 The NRC issued a Midcycle Review and Inspection Plan for Palo Verde on August 31, 2006.
18 Within the report, the NRC identified several problems and issues related to Palo Verde's decline in
19 performance. Specifically, the report indicated that

20 programmatic goals for completion of problem evaluations, consistent with
21 industry standards were routinely not met. Ineffective and incomplete corrective
22 actions led to a number of repeat problems that could have been prevented.

23 (See Jacobs Surrebuttal at 8). The report also expressed a concern about an apparent
24 tendency within the Company to permit corrective responses to lapse:

25 The inspectors noted instances where corrective actions were closed without
completion, where repeat events occurred because of slow or ineffective
corrective actions.

(See Jacobs Surrebuttal at 8, n.5).

1 These factors are relevant to the evaluation of the four outages identified as imprudent by
2 Staff witness Jacobs. In addition, these various documents also supply a framework for scrutinizing
3 Palo Verde's operations for purposes of determining whether a nuclear performance standard is
4 warranted.

5 **B. The Emergency Diesel Generator Governor Failure (March 18-21).**

6 The Company seems to claim that, because its actions did not directly precipitate the
7 condition leading to the outage, it was not imprudent. (APS' Br. at 164). The Company lists three
8 probable direct causes for the introduction of the rust that caused the governor to fail. *Id.* Staff,
9 however, believes that the Company failed to care for this equipment with the appropriate degree of
10 care. (GDS Report at 23-24).

11 As Staff witness Jacobs explained, storage of the unit with oil inside it could have prevented
12 the rust. *Id.* at 24. Indeed, the Company acknowledged that storing a governor unit with oil in the
13 reservoir would coat the internal parts and prevent rust. (Tr. at 5139-5140). This simple and low cost
14 measure could have been adopted, thereby preventing the outage.

15 APS argues that it had no reason to take this measure because it had no direct evidence that
16 rust was forming in the governor. (APS' Br. at 165-67; Tr. at 5048-49). Staff contends that this
17 position is unreasonable, given the importance of the emergency diesel generators. The EDGs are
18 necessary in the event of an emergency shutdown due to loss of off-site power. (Tr. at 5140).
19 According to NRC regulations, APS is required to shut down the unit if both EDGs are inoperable.
20 (*See* Tr. at 5041). Certainly, APS knew that the loss of an EDG over an extended period would
21 require a shutdown. Because each unit requires both EDGs to be operable in the event of a loss of
22 off-site power, and because the loss of an EDG for extended periods requires shutdown of the
23 affected unit, (Tr. at 5041), it is clear that APS did not treat the EDGs with the degree of care
24 appropriate to the significance of this particular piece of equipment. (*See* GDS Report at 24).

1 Finally, Staff acknowledges that this event took place before the PSA became effective;
2 therefore, the costs associated with this outage are not relevant to the PSA. (*See* Tr. at 5274-76).

3 **C. Unit 1 Reactor Trip and Outage Extension Due to Operator Error (August 26-28,**
4 **2005).**

5 In its brief, the Company claims that the intervening choices of one of its employees
6 supersedes managerial oversight. (APS' Br. at 160-61). This argument is not persuasive. It is the
7 Company's obligation to manage and oversee the conduct of its employees, and it ultimately must
8 bear responsibility for the consequences of their choices. The NRC was clear that there exists a
9 problem at Palo Verde regarding communication between management and personnel:

10 These concerns were associated with not having sufficient personnel to
11 accomplish long-term improvements, *a loss of trust that management would not*
12 *subject the staff to negative consequences for raising issues, some confusion*
about when to place an adverse condition into [the Company's] corrective action
program, and a decrease in confidence that the corrective action program will
adequately address problems.

13 (Jacobs Surrebuttal at 8 (emphasis added)).

14 As Staff witness Jacobs explained, Palo Verde's management knew that employees believed
15 that the digital feedwater control system did not operate correctly. *Id.* at 22. During 2005, the
16 Company had numerous opportunities to observe this phenomenon as it experienced an unusual
17 number of reactor startups. *Id.* at 22-23. The Company understood that a common mindset of
18 anticipated system failure existed, yet the Company failed to take the steps necessary to eliminate this
19 mindset. This failure to address a known problem supports the conclusion that this outage is
20 imprudent.

21 **D. Unit 2 and 3 Refueling Water Tank Inoperability (October 11-20, 2005).**

22 In its opening brief, the Company focuses on the distinction between a "static" evaluation of
23 the issue as opposed to a "dynamic" one. The Company should nonetheless have anticipated this
24 issue because of the NRC's yellow finding in 2004 on a related issue. (*See* Jacobs Surrebuttal at 24-
25 25). The yellow finding in 2004 resulted from empty containment sump piping, thereby raising

1 concerns that air entrainment from the empty sump piping could damage safety related pumps. The
2 Company had reason to be aware that the air entrainment issue, including the "dynamic" air
3 entrainment issue, was a potential concern.

4 In 2004, the NRC performed an inspection and issued Palo Verde a yellow finding owing to
5 dry sump pipes. (GDS Report at 32). In response to the issue, the Company initiated an extent of
6 condition review. The review included in its scope the RWT ECCS; as a result of that review, the
7 Company concluded that the condition was not problematic. However, when the NRC returned and
8 asked about dynamic air entrainment of the RWT ECCS, the Company was unable to respond beyond
9 relying on conformity with Palo Verde's design basis. (Tr. at 4911-15). APS witness Mattson
10 acknowledges that it was known that the proper calculation was a dynamic one thirty years ago when
11 Palo Verde was first approved.

12 You know, we knew that it was dynamic when we did the static calculation 30
13 years ago, but 30 years ago dealing with two component flow in this
14 configuration, we didn't know how to do it. It's a new technique that was used
when Palo Verde was shut down to be able to answer the question to justify the
plant being started up again.

15 *Id.* at 4915-16.

16 The Company has continuing difficulties in applying a sufficiently broad scope to analyze
17 problems. The NRC stated as much in its Fourth Quarter 2005 Reactor Oversight Program Action
18 Matrix Summary, attached to the GDS Associates Report. In notes 5, 8, and 11, the NRC specified
19 that the yellow finding for the 2004 violation was continued on the basis that "not all of the licensee's
20 root and contributing causes were fully developed, many of the corrective actions were narrowly
21 focused or ineffective, and effectiveness reviews were not adequate."

22 The Company argues that, if it had anticipated the air entrainment issue, it would have been
23 obliged to shutdown the facility, thereby forcing an outage. Staff disputes this point. At the hearing,
24 Dr. Jacobs, when asked that question, provided the following response:

25

1 There's a difference between the company finding an issue and an NRC inspector
2 identifying an issue. I think that if sometime earlier if the company had identified
3 this issue and said, we may have a problem here, we're not sure, they could have
4 gotten the time potentially to resolve it without having to shut the plant down.
5 That's not -- you know, you never really know until it happens.

6 There's a couple of mechanisms. They can declare the RWTs to be operable but
7 nonconforming. And I'm thinking the Kewaunee plant here has been mentioned,
8 and there was a similar outage up there where actually the NRC identified a
9 problem, and they took about 12 to 14 days to evaluate it before they -- and in that
10 case the plant actually did shut down, but there was a period of time where they
11 were evaluating it where they didn't immediately have to shut it down because,
12 really, the issue is you're not sure if it's operable or not.

13 So there's also the possibility that you can ask the NRC for exemption. That we
14 have this problem, we think it will be solved in three or four days, can we have
15 that period of time to work on it and resolve it? So I think there's a possibility
16 that they may not have to have it shut down.

17 The other issue is regarding the regulatory margin that we talked about. If you're
18 in the Palo Verde situation and an issue like that comes up, the NRC is probably
19 going to be reluctant to give you any exemption to the time period. But if you
20 were, you know, a top performing plant, you might have a better chance of not
21 having to shut down. So there's a chance that they wouldn't have had to shut
22 down. I can't say definitively one way or the other.

23 (Tr. at 5343-44).

24 The Company should have known that air entrainment damage to pumps is a safety concern
25 and should have defined its analysis of the issues related to the yellow finding in a manner that would
26 encompass all similar issues. Draining down the RWT gives rise to the same air entrainment
27 concerns as the empty sump piping, and APS' failure to identify this issue demonstrates a lack of
28 rigor in its analysis.

29 In surrebuttal, Staff witness Jacobs pointed out that the NRC had already identified numerous
30 crosscutting issues, *i.e.*, issues affecting several areas of plant organization:

31 Crosscutting themes identified in this component involved inadequate evaluations
32 of problems and untimely implementation of corrective actions. Examples
33 include: failures to address the extent of condition of problems; failures to fully
34 evaluate problems resulting in repetitive or long-standing problems affecting
35 safety systems and components; failures to correct known degraded conditions in
36 a timely manner. The crosscutting themes identified during this assessment are
37 similar to those that have been identified in previous NRC assessments,

1 particularly with respect to inadequate evaluation of conditions adverse to quality,
2 as well as inadequate and effective correction of problems.

3 (See Jacobs Surrebuttal at 11-14). This evaluation notes APS' failure to fully evaluate issues that cut
4 across multiple facets of plant operations.

5 APS knew or should have known that air entrainment issues in the RWT were raised by the
6 2004 yellow finding, and APS knew or should have known that its problem identification and
7 analysis tended to be too narrowly focused. A reasonably complete analysis of the issues related to
8 the 2004 yellow finding would have permitted the Company to identify this issue. *Id.* at 24-25. This
9 outage was therefore avoidable and imprudent.

10 **E. Measuring the Impact.**

11 In addition to disputing the imprudence of the previously discussed outages, the Company's
12 brief raises several issues related to measuring the costs of imprudence.

13 ***1. Offsetting coal operations against the Impact of Palo Verde Outages is not***
14 ***Reasonable.***

15 The Company argues that the strong performance of its coal plants mitigates the costs of the
16 imprudent outages. (APS' Br. at 149). This contention is unpersuasive. The improved performance
17 of APS' coal generation is not related to the Palo Verde outages, and the fact of improved
18 performance of the coal plants highlights the loss of Palo Verde, which could have had excess power
19 to sell off-system.

20 The Palo Verde outages should be considered in isolation. In spite of the improved
21 performance of the coal plants, this improved performance did not prevent the costs incurred by the
22 Palo Verde outages. The Company's brief seems to imply that, without the Palo Verde outages, the
23 improved performance of the coal plants would not have occurred. (See APS' Br. at 175) The
24 Company, however, supplied no testimony to the effect that the improved performance of its coal
25 plants was caused by the Palo Verde outages or was in any way connected with the outages.

1 The calculation of the costs of the outages of necessity nets the cost impact on the entire
2 system. The impact of the improved performance of the coal plants was already counted in the
3 system balancing that still necessitated purchasing replacement power. (Jacobs Surrebuttal at 45).
4 Consequently, the improved performance of the coal plants should not be considered as a mitigating
5 factor because it is unrelated to the Palo Verde outages and would result in double counting.

6 2. *Lost Off-System Sales.*

7 In its opening brief, the Company concedes that the outages have decreased off-system sales,
8 but the Company disagrees with Staff's calculation of the measure of these lost sales. (APS' Br. at
9 175). In developing its testimony, Staff asked the Company provide additional information to
10 support APS' proposed adjustments to reflect margins related to lost off-system sales. (Jacobs
11 Surrebuttal at 41). In response, the Company provided the results that it developed using a
12 production cost model. Although the Commission has approved the use of this methodology before,
13 Staff is concerned about the inputs chosen by the Company in its analysis. As Staff witness Jacobs
14 explained,

15 [Y]ou have the model, and then you have the application of the model. And just
16 because the model has been accepted, that doesn't mean that in any particular
17 application, given all of your assumptions going into it, that your answer is going
to be correct.

18 (Tr. at 5312). In surrebuttal, Staff had already expressed concerns about the inputs chosen by the
19 Company in its analysis.

20 Principally, Staff focused on the improbability of two significant assumptions that the
21 Company made in its analysis. First, the Company assumed that the lost sales would occur only
22 during the times when Palo Verde was shutdown due to an imprudent outage. (Jacobs Surrebuttal at
23 41). Second, the Company assumed that APS was not buying power in the wholesale market. *Id.*
24 Staff contends that neither assumption is reasonable because the outages may be the events that
25 caused APS to purchase wholesale power. *Id.* at 41-42. Further, the analysis appears to incorporate

1 errors. For example, it assumed lower off-system sales when Palo Verde was operating than when it
2 was out-of-service. And in some circumstances, the simulation produced lower margins even though
3 the level of lost generation in off-system sales increased. *Id.* at 42. Clearly, the Company's analysis
4 introduces more questions than it resolves in terms of the quantification of margins on lost off-system
5 opportunity sales. Consequently, Staff's position on the amount of lost off-system sales should be
6 adopted.

7 **3. *The Nuclear Performance Standard is an Appropriate Responsive Measure.***

8 In response to the ongoing issues regarding Palo Verde's decline in performance, Staff
9 recommends that the Commission create a Nuclear Performance Standard ("NPS"). The Company,
10 in its opening brief, expressed several reservations about such a plan. The Company suggests that the
11 plan should include incentives as well as caps on penalties so as not to jeopardize the Company's
12 attention to safety. (APS' Br. at 168-169, 171-175). The Company also believes that coal generation
13 should be included in the implementation of any performance standard. *Id.* at 173-174. Finally, the
14 Company believes that more information is necessary to implement a NPS than has been developed
15 to date. *Id.* at 169-71.

16 The Commission should adopt a performance standard to govern the operation of Palo Verde.
17 The Company will recover its cost of invested capital regardless of the quality of its performance, and
18 the ratepayers therefore bear the risk of poor performance. (Jacobs Surrebuttal at 35). This is unfair
19 when one considers that nuclear plants have exceptionally high capital costs and that only the low
20 costs of fuel and operations offset the high capital costs. The lower cost of operations can only be
21 achieved when the plant operates at a high capacity factor. Adopting a reasonable NPS will alleviate
22 this situation by placing the costs of inefficient operations on both the Company and its ratepayers.
23 (Tr. at 5128, 5225).

24 Staff's proposed NPS is reasonable and does not jeopardize safety. Dr. Jacobs explained that
25 incentives rarely influence a company in a positive manner and therefore typically end up subsidizing

1 a company for unchanged behavior. (Jacobs Surrebuttal at 35). As to dead bands and penalty caps,
2 Staff's proposed NPS already incorporates a three-year sampling for evaluations. Consequently, the
3 plan provides an added buffering influence of several years of performance to alleviate the impact of
4 an atypical year. (See Jacobs Surrebuttal at 37).

5 With respect to the Company's proposal to include all base load generation in the
6 performance plan, Staff believes that such an all-inclusive plan would not serve any useful purpose.
7 Coal and nuclear power are fundamentally different. (Jacobs Surrebuttal at 36). Their fixed and
8 variable costs are largely reversed, and their methods of operation and basic regulatory regimes are
9 fundamentally different. A broad performance standard encompassing the Company's entire
10 baseload generation would permit the Company to gloss over the performance of its single most
11 costly asset, Palo Verde.

12 In response to the Company's concerns regarding the lack of specificity contained in the NPS,
13 Staff has acknowledged that the NPS may be subject to various modifications that the Commission
14 may elect to make. *Id.* at 38. However, as Dr. Jacobs testified, Staff's proposed NPS is sufficiently
15 detailed to implement as written. *Id.* at 38-39.

16 **XII. ENVIRONMENTAL IMPROVEMENT CHARGE**

17 Among its arguments in support of its proposed environmental improvement charge ("EIC"),
18 APS notes that its proposal is not a contribution in aid of construction, but is instead more analogous
19 to CWIP. (APS' Br. at 100). Staff disagrees with this characterization.

20 The proposed EIC is certainly novel and is therefore somewhat difficult to precisely
21 categorize. Nonetheless, the proposed EIC is designed to entirely recover many of APS' costs—
22 including capital costs—in advance, thereby eliminating the need for APS to actually make an
23 investment before recovering the costs of that investment. The following testimony illustrates this
24 potential:

1 Q. [U]nder your proposal is it intended that the EIC will be collected before some
2 of the costs are incurred?

3 A. The EIC is intended, again, to collect costs that are anticipated to be incurred
4 over the forecast period.

5 Q. So the answer to my questions is yes, I think?

6 A. Yes, subject to true up.

7 Q. Does the EIC provide a means for APS to earn a return on projects before
8 they're actually rate-based?

9 A. Yes.

10 Q. Does the EIC provide a means for APS to earn a return on a project before it
11 has begun?

12 A. Possibly.

13 (Tr. at 2489-90). In some respects, the proposed EIC is akin to ratepayer-supplied capital, yet APS'
14 proposal does not appear to provide any recognition of this principle. For example, APS' proposed
15 EIC does not include provisions for appropriate rate base deductions to give ratepayers some benefit
16 for having supplied capital. The proposed EIC is therefore somewhat one-sided, and Staff believes
17 that this design is not equitable. For this reason, Staff believes that the Commission should reject
18 APS' proposed EIC.

19 **XIII. DEMAND SIDE MANAGEMENT**

20 APS once again argues that it should be allowed to recover its proposed "conservation
21 adjustment" for revenues lost as a result of its DSM programs. (APS' Br. at 69). Staff maintains its
22 position that such a pro-forma adjustment should not be allowed because the revenue reduction is not
23 known and measurable. (Anderson Surrebuttal at 7). Staff believes that APS should be compensated
24 for its efforts to make DSM programs available and for the savings achieved by those programs
25 through a performance incentive. (Anderson Direct at 9).

APS also states that the Company proposes, and SWEEP and Staff agree, that any unspent
funds should be carried over and spent in subsequent years." (APS' Br. at 118). Staff would like to

1 clarify that it does *not* agree that unspent funds should be carried over and spent in subsequent years.
2 Staff stated clearly that, if during 2005 through 2007, APS does not spend at least \$30 million of the
3 base rate allowance for approved and eligible DSM-related items, the unspent amount is to be
4 credited to the account balance of the Demand Side Management Adjustment Clause ("DSMAC")
5 account. (Anderson Surrebuttal at 2). These are monies paid by APS' customers through base rates.
6 If the \$30 million collected in this manner has not been spent during the 2005 through 2007 period,
7 then it should be given back to the customers who paid it. (Tr. at 3634).

8 **XIV. POWER SUPPLY ADJUSTER**

9 Staff continues to oppose the inclusion of broker fees in the power supply adjuster ("PSA").
10 At the hearing, Staff witness Antonuk explained the reasons for excluding broker fees:

11 [M]y understanding is that the Staff who worked on the PSA the last time was
12 comfortable in the conclusion that there had been a removal of them. So I treated
13 that as precedent, you know. It was established. That was the rule. So this
14 reflects the rule.

15 (Tr. at 4009). Staff considered the exclusion of broker fees to be established precedent, and therefore
16 adopted a consistent position in this case.

16 **XV. RATE DESIGN**

17 Concerning Rate E-32, Staff has noted its hesitation to raise demand rates significantly over
18 levels proposed by APS. (Staff's Br. at 66). This concern is prompted by two factors: 1) the last rate
19 case significantly raised the demand charge for customers above 20 kW so that some lower load
20 factor customers received increases significantly greater than the system average increase; and 2) this
21 adoption of a higher demand rate is fairly new in that current rates have only been in effect for
22 approximately eighteen months.

23 This same concern is also applicable to a rate proposal sponsored by AECC witness Higgins.
24 Specifically, AECC proposes to pass through the transmission charge in the demand portion of Rate
25 E-32. Entirely aside from the possible cost-of-service merits of this proposal, Staff is concerned that

1 it will result in a substantial rate increase to a segment of APS' customers who have recently
2 experienced rate increases that are significantly greater than the system average. In order to promote
3 the principle of gradualism in rate design, Staff opposes this AECC proposal at this time.

4 **XVI. DEMAND RESPONSE**

5 Staff has recommended that APS conduct a study to identify the types of demand response
6 and load management programs that would be most beneficial to APS' system. Staff has also
7 recommended that APS file for Commission approval one or more cost effective demand response or
8 load management programs. Staff has suggested that both of these items should be filed with the
9 Commission within eight months of a Commission decision in this matter. If APS needs more than
10 eight months to complete these filings, Staff would not object to extending the deadline.

11 In its brief, APS appears to misunderstand these proposals. APS states that, "[a]lthough Staff
12 has proposed an eight-month feasibility study, the Company believes that truly effective Demand
13 Response programs cannot be implemented, analyzed, and introduced to all customers in such a short
14 amount of time. (APS' Br. at 123). Staff wishes to clarify that its proposal does not envision full
15 implementation and introduction "to all customers" within an eight-month period. Instead, Staff
16 intended for the study and associated programs to serve as a means to initiate consideration of these
17 issues. In any event, Staff is not opposed to extending the due date for these filings beyond eight
18 months.

19 **XVII. MISCELLANEOUS ISSUES**

20 There are a number of items that APS has proposed *after* the filing of its direct case:

- 21 1) In rebuttal testimony, APS proposed a number of changes to various
22 partial requirements tariffs as well as a number of proposed new partial
requirements tariffs. (APS' Br. at 95-99).
- 23 2) After the conclusion of the hearing, APS provided a late-filed exhibit
24 related to one of its proposed solar schedules.
25

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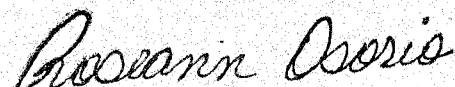
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